In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning	))))	Docket No. EO-11050309

Comments of

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on behalf of
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I. INTRODUCTION AND SUMMARY

Thank you for allowing me to submit these comments in addition to what I submitted for the October 14th public hearing at which I was scheduled to testify on behalf of Exelon Corporation. I have had the privilege of testifying previously before the New Jersey legislature, as well as the legislatures in Maryland and Ohio regarding electric market restructuring and competition. In 2006, I also testified previously on behalf of the BPU regarding the proposed merger between Exelon and PSEG, and last year testified for the Maryland Public Service Commission regarding the merger between FirstEnergy and Allegheny Energy. I also worked as the Director of Planning for the Vermont Dept. of Public Service, the consumer advocate for that state. I believe strongly in the benefits of competitive electric markets and in appropriate oversight of those markets.

The Board of Public Utilities (Board or BPU) has set out ten broad topics for which it seeks answers at this hearing. Most of them address "perceived" shortcomings in the PJM capacity market and how to address those "perceived" shortcomings. My comments will focus on the following BPU questions:

- Is there sufficient capacity to ensure "the lights stay on" in New Jersey? How has the economic recession affected PJM's load forecast and the need for new capacity to ensure reliability is maintained?
- Why are higher Reliability Pricing Model (RPM) market-clearing prices in New Jersey not incenting construction of new generating resources in the state, even though such resources are being built in other parts of PJM that have lower market-clearing prices?

- Is it possible to develop baseload and intermediate (*i.e.*, mid-merit) generating resources under the current RPM design, or are longer-term contracting mechanisms needed?
- How have lower demand forecasts and changes in planning parameters affected the need for new capacity in New Jersey?
- Should the state's local electric distribution companies (EDCs) withdraw from RPM and instead provide capacity under the Fixed Resource Requirement (FRR) alternative?

These are all reasonable questions to ask, and I hope my comments today will help answer them. However, I use the word "perceived" because some of the questions reflect an incomplete understanding of how PJM's wholesale electric capacity market operates.

In brief, I believe the PJM capacity market is working well. The market results are competitive and the Independent Market Monitor (IMM) rigorously monitors the capacity market to ensure it remains so.[1] The PJM Capacity market has also been found to be competitive and working well in two independent assessments by the Brattle Group.[2] Moreover, RPM capacity prices have been shown to be much lower than what was initially predicted when electric restructuring began.

One of the reasons RPM works is by incenting the lowest cost capacity resources to be added to existing capacity supplies when required to meet

[1] *See e.g.*, IMM, *2011 Quarterly State of the Market Report for PJM: January through June*, at 117.

[2] *See* The Brattle Group, "Review of PJM's Reliability Pricing Model (RPM)," June 30, 2008, and "Second Performance Assessment of PJM's Reliability Pricing Model Market Results 2007/08 through 2014/15," August 26, 2011 ("Brattle Report").

demand. Over 6,700 MW of new capacity in the form of generator uprates, repowerings, and new generating capacity have been added in PJM since RPM began in 2007. In addition, RPM has brought almost 15,000 MW of demand response capacity to the market since 2007, with over 2,000 MW of that from New Jersey. These additions make sense, because consumers benefit most when the lowest-cost resources are added first. Uprates and repowerings of existing generation are less costly than building new plants. Existing businesses and industry can provide demand response which, unlike new generation, does not require lengthy siting and environmental approvals, and delays the need for new generation in some areas.

This is not to suggest that the current RPM market design cannot be improved. For example, in his June 17th comments before the NJ BPU, Joseph Bowring, the PJM IMM, suggested several RPM market enhancements to reduce uncertainty over future planning parameters.[3] More recently, on August 26th, the Brattle Group, from whom Mr. Frank Graves is here today to testify, issued its second assessment of the PJM RPM.[4] That report suggests several modifications to further improve RPM design, such as the addition of voluntary longer-term auctions to ensure greater price certainty for generators and help incent new generating capacity when it is needed.

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[3] Comments of the PJM Independent Market Monitor, June 17, 2011, at 2-3.

[4] The Brattle Group, "Second Performance Assessment of PJM's Reliability Pricing Model Market Results 2007/08 through 2014/15," Report prepared for PJM Interconnection LLC, August 26, 2011 ("Brattle Report").

Nevertheless, the topics raised for this hearing reflect concerns about whether RPM is really working as it should be. This leads to two fundamental policy questions: first, can markets be trusted to ensure "the lights stay on in New Jersey?"; second, does New Jersey need to adopt "non-market" or "command-and-control" approaches to ensure the lights stay on.

First, markets can be trusted to ensure the lights will stay on in New Jersey. Because electric reliability is what economists call a "public good,"[5] a separate market-based capacity structure, such as PJM's RPM, makes economic sense. As the New England and New York ISOs did, PJM developed a market-based capacity structure to help ensure sufficient capacity would be available when needed.[6] RPM continues to incent sufficient capacity, including existing capacity, new capacity, and demand side resources. Furthermore, completion of the Susquehanna – Roseland 500 kV transmission line, which the Federal government has identified as a high priority, will relieve transmission constraints and increase New Jersey consumers' access to lower cost supplies throughout PJM.

Secondly, New Jersey should not adopt more "command-and-control" measures to ensure the lights stay on. Non-market solutions substitute the judgment of politicians and regulators for the rigorous discipline of the marketplace. Yet, history has shown repeatedly that politicians and regulators, however well-intentioned, fare far worse than markets in determining the most

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5 For a more detailed discussion, *see* J. Lesser and G. Israilevich "The Capacity Market Enigma," *Public Utilities Fortnightly* 143 (December 2005): 38-42 ("Lesser and Israilevich 2005").

6 *Id*.

efficient "winners and losers" and that such non-market "solutions" <u>always</u> have unintended adverse consequences.

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Let me now turn to the topic: If RPM is working, why isn't more generating capacity being built in Northern New Jersey, especially since capacity prices there are higher than in PJM as a whole?

A number of factors contribute to this. As with all competitive markets, RPM is designed to elicit the lowest cost available capacity supplies first. Additionally, New Jersey has higher costs – land, labor, permitting, and so forth – that disincent new construction. In fact, **the cost of constructing a new CT or CCGT in NJ is higher than in all other areas in PJM**, as shown in PJM's calculation of gross CONE (*i.e.*, cost of new entry not including any energy or ancillary revenues) for the 2014/2015 RPM auction: the gross CONE for a new CCGT in the NJ zones was on average $18,000/MW-year higher than the average gross CONE for all other zones in PJM.[7] For a 500 MW CCGT, that means almost $1 million in higher construction costs that must be recouped annually.

Perhaps most importantly, however, are the unintended adverse consequences from the state's Long-Term Capacity Agreement Pilot Program (LCAPP). Although FERC's Minimum Offer Price Rule (MOPR) has rendered the LCAPP strategy problematic, this state's decision to circumvent RPM and artificially reduce market-clearing prices has created investment uncertainty and a powerful "<u>Do Not Invest in New Jersey</u>" signal to generation developers.

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[7] Source: <u>http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110413-ct-cc-minimum-offer-price-for-2014-2015.ashx</u>).

Regulatory uncertainty is especially problematic for long-lived, capital intensive investments such as electric generating plants. Uncertainty over future non-market policies the state might choose to implement creates a powerful economic disincentive for any new, market-based investment. Thus, generation developers will be much less willing to risk making investments based on expectations of future market prices, <u>if they believe the state will intervene in the market to artificially reduce those prices</u>. The resulting self-fulfilling prophecy creates a vicious cycle: the state intervenes because it believes the market is not working and RPM prices are too high; such state intervention discourages new investment; that lack of new investment reinforces the belief that the market is not working, which produces more demands on the state to mandate additional non-market policies, which reinforces investor uncertainty. The lesson is clear: resist the urge to "do something," and let the market work as it is intended.

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A related topic identified asks whether the RPM can incent mid-merit and baseload capacity. In part, the answer is "it already has." This new generation primarily has come from uprates and repowering existing generating facilities, not the more expensive greenfield development. Significantly, however, given existing excess capacity supplies and reduced electric demand because of the economic recession, there is no current need for new baseload and mid-merit capacity. Recent analysis by CERA, for example, projects that PJM has sufficient capacity through at least the year 2020.[8] This also helps explain why only two

[8] In line with a sharp downward revision to the outlook for economic growth and electricity demand, IHS CERA now projects reserve margins in RFC-PJM to remain above the target level until 2020. The

new gas-fired generating facilities have come on-line since 2006 in the MAAC zone. The need for new generating facilities has been supplanted by plentiful capacity and lower-cost alternatives.

A second implied question within this topic is whether such generation can be built in New Jersey, or is it more likely to be built elsewhere? The higher construction costs in New Jersey, coupled with the tremendous investment uncertainty, will discourage major investment in baseload and mid-merit capacity.

As for improvements to the RPM market design, I have already mentioned recommendations by the Brattle Group for voluntary longer-term auctions to improve price certainty. I believe this idea has great merit and hope PJM can implement this idea in conjunction with the auctions for the 2015/16 planning year, which begin next May.

Regarding longer-term, fixed price contracts, unless those contracts are set by market forces I fear we simply would repeat the costly experience of the Public Utilities Regulatory Policy Act of 1978 (PURPA), which led to long-term expensive, far above-market generating capacity which raised customers' rates for many years.

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current pipeline of plants under construction, uprates to existing resources and strong growth in demand resources is expected to delay the need for new capacity additions despite projections of nearly 12 GW of capacity retirements by 2020. This analysis reflects the fundamentals of the broad market area; the year of need may vary slightly within a region depending on specific local transmission constraints.

The last question posed by the Board inquires whether New Jersey should pursue the FRR alternative to avoid paying RPM prices. Based on my recent experience in Ohio, New Jersey consumers would not benefit under the FRR option, as FRR entities will try to recover the higher of their embedded capacity costs or the market price.

Currently, the only two FRR entities in PJM are AEP Ohio and Duke Energy Ohio (Duke Ohio). Both utilities have argued they are entitled to recover the full embedded costs of the generating resources they use to meet their FRR obligations, even though PJM rules provide no such guarantee.[9] Further, the embedded cost values they have calculated are far higher than RPM market-clearing prices. AEP Ohio, for example, has estimated its embedded cost at $355/MW-day,[10] which will increase with anticipated capital investments in new environmental controls. By comparison, the average RPM "Rest of RTO" (where both AEP Ohio and Duke Ohio are located) market-price for the 2011/12 planning year, which began on June 1, 2011, through the 2014/15 planning year, is $70/MW-day. **Thus, under its FRR, AEP sought to charge customers for capacity at five times the market rate.**

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[9] FERC rejected AEP Ohio's initial argument that it be allowed to charge a capacity cost sufficiently high to recover its embedded costs. *American Electric Power Service Corporation*, 134 FERC ¶ 61,039 (2011). In response, AEP Ohio has filed a Complaint pursuant to Section 206 of the Federal Power Act to amend Schedule 8.1, Section D(1)(8) of the RAA to permit it to file for new, cost-based wholesale capacity charges.

[10] *See* Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, Direct testimony of Kelly D. Pearce in support of the Stipulation and Recommendation on behalf of Columbus Southern Power Company and Ohio Power Company, September 13, 2011, Exhibits KDP-1 and KDP-2. This testimony is part of a contested partial Stipulation that AEP Ohio filed with the PUCO on September 7, 2011. This value includes transmission system losses.

Similarly, Duke Ohio proposed to charge all customers, both shopping and non-shopping, for capacity at its embedded cost, net of 80% of profits for energy and ancillary services sales. Duke Ohio projects the resulting capacity charges to average about $220/MW-day over the four-year planning period. Although less than AEP Ohio's almost $355/MW-day price, **Duke Ohio's proposed FRR capacity price was still over three times the average PJM RPM market-clearing price.** Moreover, the Duke Ohio proposal essentially guarantees consumers have to pay an above-market regulated rate of return on the capacity investment.

In December 2008 testimony before the Pennsylvania Public Utility Commission, Dr. Roy Shanker compared cost-based capacity rates projected during PECO's electric restructuring filing against RPM's market-based capacity prices, concluding the figures demonstrated convincingly that allegations of excessive capacity payments under RPM are unjustified.[11] According to Dr. Shanker's analysis, even ignoring stranded costs associated with Pennsylvania generating units, the PJM RPM capacity prices, year over year, were comparable or lower than the capacity costs that would have resulted under traditional cost-based regulation.[12]

Finally, under PJM rules, an FRR designation requires a minimum five-year commitment. Thus, if New Jersey EDCs become FRR entities, New Jersey

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[11] *En Banc* Public Hearing on "Current and Future Wholesale Electricity Markets," statement of Dr. Roy Shanker, December 18, 2008. Available at: http://www.puc.state.pa.us/electric/pdf/EnBanc-WEM/Ttmy-RShanker121808.pdf.

[12] *Id*. at 13.

will have to live with the consequences—and likely higher capacity costs— for at least five years.

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In summary, I urge the BPU to resist the urge to "do something," and let the PJM RPM continue to work, as it has. The lights are not going to go out in New Jersey and further command-and-control solutions, whether new rounds of LCAPP or requiring EDCs to become FRR entities, will disincent current and future investment in the state and raise electricity costs. That, in turn, will damage the New Jersey economy and lead to lost jobs.[13]

II. WHY HAS THE MARKET RESPONDED WITH DISPROPORTIONATELY GREATER AMOUNTS OF NEW GENERATION CAPACITY BUILT OUTSIDE OF NORTHERN NEW JERSEY IN REGIONS WITH LOWER RPM CAPACITY CLEARING PRICES?

The relative lack of new generating capacity built in New Jersey since RPM's inception in 2007 raises an observational question: how can RPM be working if new generation is being built in regions where RPM clearing prices are lower than in Northern New Jersey?

I believe there are four reasons, all of which confirm that, in fact, RPM is working. First, although RPM clearing prices have been higher in Northern New Jersey than in the PJM RTO as a whole, the prices have not been sufficiently high

[13] See "Electricity Competition at Work: The Link Between Competitive Electric Markets, Job Creation, and Economic Growth," Continental Economics, Inc., Report prepared for the COMPETE Coalition, September 2011. Available at: http://www.competecoalition.com/resources/new-compete-study-shows-competitive-electricity-markets-support-economic-growth-and-job-cr.

to support new generating plant investments, especially larger, higher-cost baseload generating units.[14] As I explain in more detail below, the decision to build a new generating plant is a complex one based on long-term expectations of capacity and energy prices, as well as investment and operating costs. Second, although new generation plants are currently not being built, that does not mean that new capacity resources are not being developed. They have been, and continue to be. The addition of lower cost supply alternatives, such as demand response resources and power uprates, further delays the need for new generation plants to be built.

Third, other regulatory impacts, such as more onerous local siting requirements and higher construction costs can disincent new generation development. As explained above, New Jersey is the most costly region of PJM to build new CTs and CCGTs. Fourth, and most importantly, New Jersey's previous non-market intervention in the RPM through the first round of generating capacity acquired under LCAPP, and proposals to continue intervention through additional rounds of LCAPP, are a self-fulfilling prophecy which thwarts economic market-based investment. Forcing EDCs to either build new generating resources or sign long-term contracts with generation developers, along with guaranteed cost recovery through non-by passable

[14] *See* IMM, State of the Market Report 2010, Volume 5, for a discussion. PJM estimates the net cost of new entry ("CONE"), which is the price at which a new generator entering the market would require to have a reasonable expectation of profitability. PJM RPM prices, even in PS-North, have consistently been below the net CONE values. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010/2010-som-pjm-volume2-sec5.pdf.

charges, forces New Jersey consumers to subsidize such generating capacity, and discourages market-based investment.

A. The Economics of New Generating Capacity Investment Decisions

Building a new generating plant requires hundreds of millions, or even billions of dollars for large, baseload facilities. PJM provides investors with market signals for both future energy and capacity prices. Future energy prices can be identified from published forward and futures prices,[15] which typically extend about five years.

Organized exchanges like NYMEX serve as market-makers. They eliminate the risks to individual contracting parties and take on a contract's "performance risk" themselves. Thus, a load serving entity (LSE) that buys electricity futures on NYMEX to meet its anticipated customer demand for electricity next year does not have to worry about the supplier of that electricity actually providing it.

PJM serves this same function. Buyers and sellers of energy in the day-ahead and real-time markets can rely on PJM to "make good" on their transactions. Similarly, capacity transactions are guaranteed. PJM will never "deny" capacity to an EDC if it has purchased the capacity required to meet reliability standards.

For capacity investors, expectations of future prices are clearly important. Thus, whereas the RPM price in PS North for the 2014/2015 planning year is

[15] Futures prices are defined for uniform contracts. For example, on NYMEX, one peak electricity futures contract totals 80 MWh delivered at a rate of 5 MW per hour during peak hours.

$225/MW-day, completion of the Susquehanna – Roseland 500 kV transmission line will relieve transmission constraints and lower future market prices in the PS North zone. In fact, on November 1, 2010, PJM released the results of requested sensitivity studies on the Susquehanna – Roseland line's effects on RPM prices in New Jersey, relative to the actual $245/MW-day market-clearing price in the 2013/2014 RPM.[16] PJM's analysis showed that adding the line would have reduced the market-clearing price by over 6%, resulting in a new price of about $230/MW-day.[17] PJM also modeled adding both the Susquehanna – Roseland line and the PATH project, finding that together they would cut the PS-North price almost in half, to $136/MW-day, which would be the prevailing price in all of the PJM zones (*e.g.*, MAAC, PEPCO, PSEG, etc.).[18]

As the PJM analysis shows, new transmission capacity will reduce or eliminate existing constraints, lowering the price of capacity in PS-North. A developer evaluating construction of new generating capacity in the PS-North zone would therefore consider not only the high development costs in New Jersey, and the continuing regulatory uncertainty, but also the likelihood of completion of both the Susquehanna – Roseland and PATH lines would also reduce market-clearing prices, and therefore the economic benefits of generation development.

[16] A copy of the analysis can be downloaded from: http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/scenario-analysis-results.ashx.

[17] *Id*. This is shown as Scenario 19 in the PJM analysis.

[18] *Id*. This is shown as Scenario 20 in the PJM analysis.

1. <u>Relative Prices Matter</u>

Another factor that affects generation investment decisions, and the types of capacity offered, are the relative prices of different types of capacity. As markets always incent the most economic investments, lower-cost resources will be developed before higher-cost ones. Even though RPM prices in Northern New Jersey are now higher than in PJM as a whole, the relative prices of different sources of capacity still determine which resources are developed first.

Demand response resources, for example, are less costly than building new generation, as they avoid land, labor, permitting, and construction costs. Similarly, uprates to existing generation increases electricity output for significantly less money and require less time than greenfield development. Again, this is especially true in New Jersey. Thus, economic principles suggest proportionately more demand response, uprates and repowerings will be developed than new generation build. Indeed, in its testimony before the Board on June 17, 2011, PJM confirmed that in the 2014/15 RPM auction approximately 2,000 MW of demand response resources in New Jersey had cleared, which is more than three times the capacity of the Oyster Creek Nuclear Generating Station and represents about 70% of all demand response in the EMAAC zone.

2. <u>Long-term investment decisions do NOT require long-term contracts</u>

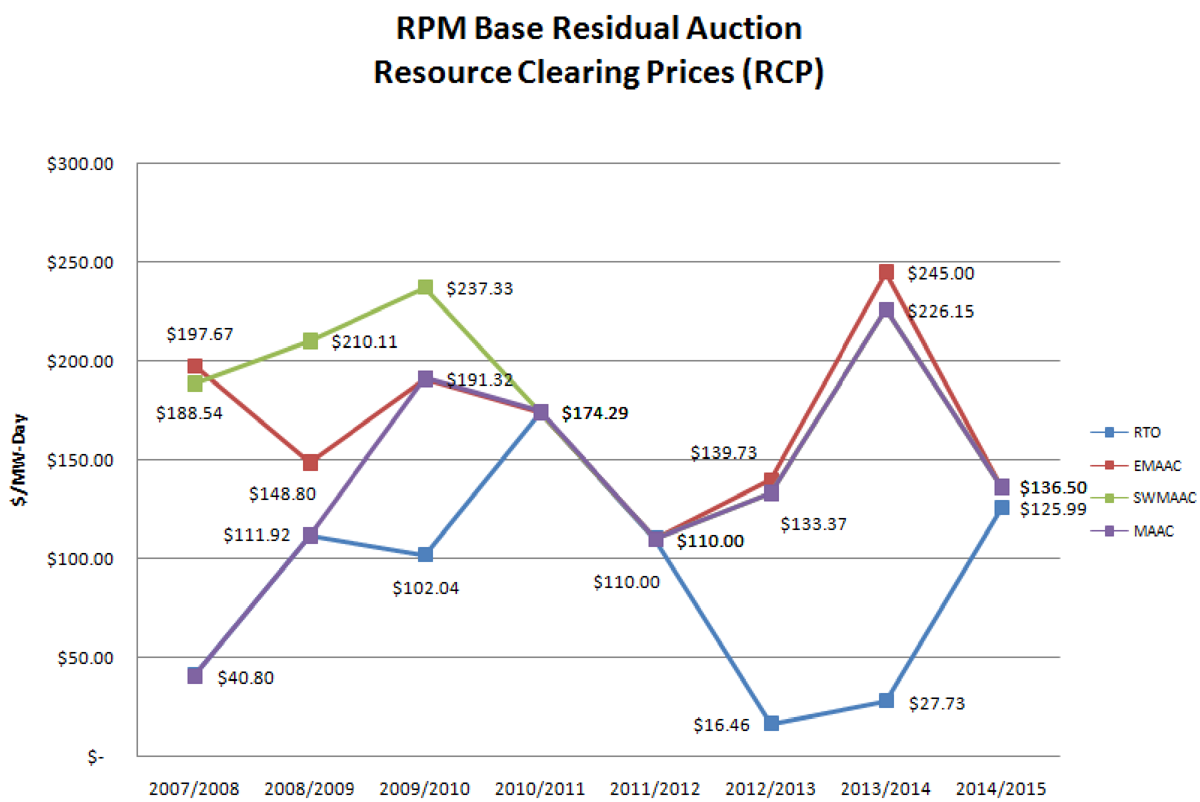
Generating plants have economic lives far longer than five years, thus investment decisions must evaluate how electricity prices will change over time. In the case of electricity, there are significant regulatory uncertainties that can affect future energy and capacity prices. For example, the economics of operating baseload coal-fired plants are affected by future environmental regulations, such as reductions in sulfur dioxide emissions, NOx emissions, and mercury, and carbon limitations. PJM capacity prices are affected not only by factors such as these, but also the parameters defining the capacity demand (or "VRR") curve, and planned transmission system additions.

In spite of the challenges in predicting long term prices, significant quantities of capacity in PJM are exchanged with bilateral contracts, as nothing in the RPM design precludes market participants from entering into contracts of any length they believe to be cost-effective. An EDC or LSE entering into such a contract must determine whether the contract risks outweigh its benefits of longer-term price certainty and delivery.

If, however, New Jersey requires EDCs to enter into long–term, fixed price capacity contracts, consumers will be forced to bear all of the financial and performance risks as happened under PURPA, where regulators mandated high-priced, 20 to 30-year contracts with generation developers based on wildly inaccurate price forecasts. Thus, before the BPU concludes that long-term contracts are "the solution," it must carefully consider the consequences of contract prices that turn out to be far higher than the market.

Furthermore, in contrast to long-term contracts, markets are self-correcting. Consider, for example, the clearing prices in the RPM auctions since its inception in 2007, as shown in Figure 1.

Figure 1: RPM Clearing Prices



Source: 2014/2015 RPM Base Residual Auction Report. http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx.

PJM's RPM provides transparent price signals which influence investment decisions. Lower RPM prices are followed by higher prices, as unnecessary supplies are withdrawn, whereas higher prices incent new supply into the market, causing prices to moderate.[19] Because the PJM RPM provides clear price signals, it provides critical information to EDCs, LSEs, and capacity suppliers to

[19] In part, the individual zone prices are also the result of changing planning parameters and determinations of whether those individual zones are constrained. Nevertheless, the general pattern clearly does respond to market signals.

inform investment decisions. Replacing such a well-defined capacity market with mandates requiring EDCs to enter long-term contracts, eliminates that vital information.

Mandating long-term contracts also will damage retail competition because competitive retail suppliers will be forced to take on greater levels of risk, which they will need to compensate for through higher prices. Those higher prices will reduce the incentive for consumers to shop for electricity, leading to less innovation and, ultimately, higher electric prices for everyone. Such an outcome, in turn, will have broader economic impacts that ripple through the New Jersey economy.

B. The Self-fulfilling Prophecy of Non-Market Intervention

Non-market intervention based on an assumption that politicians and regulators can somehow "beat the market" not only is almost always wrong, but also damages markets themselves. This creates a self-fulfilling prophecy that ultimately harms the very consumers who were to benefit.

In competitive markets, benefits accrue over the long run relative to regulated rates. To judge wholesale competition a "success" only if the resulting wholesale market prices are below embedded costs at all times is both unreasonable and unfair.

Yet, LCAPP, an artificial intervention in the PJM capacity market, is premised on just such an "always lower prices" test. The idea was that forcing New Jersey consumers to subsidize otherwise uneconomic generation investments would provide greater benefits in the form of lower RPM. This is really a form of "free-lunch" economics in which everyone benefits, except for competitive generators – the generators that New Jersey wants to build in the state.

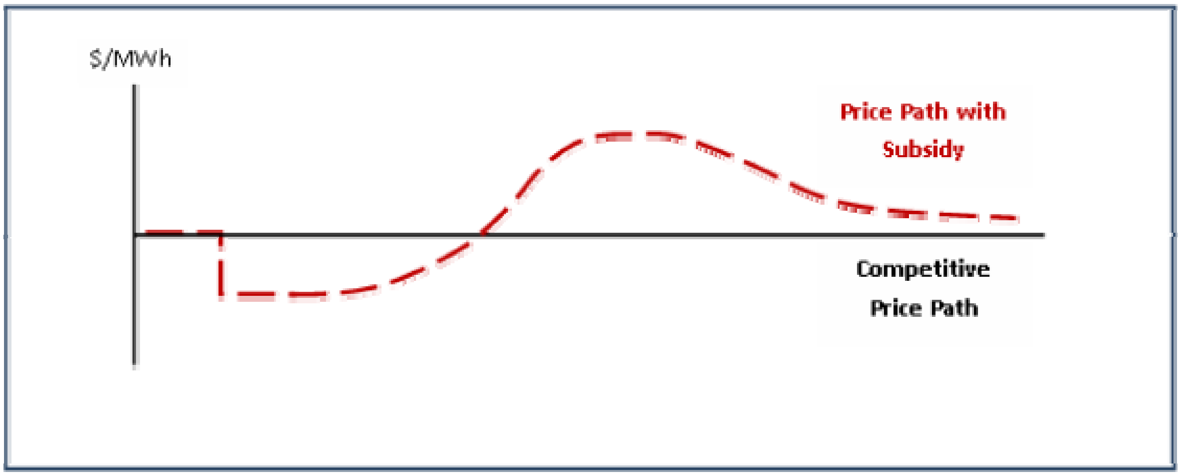
By definition, a subsidized generating plant is uneconomic. By artificially depressing capacity prices, however, New Jersey drives out legitimate competitive generators, so any price reductions are temporary. Worse still is the long-term damage to markets. By driving out legitimate competitors, LCAPP-type policies increase financial risk, as investors don't know if a generating plant they finance will be forced out of business in the future by some other state policy action.

Finally, subsidies reduce the incentive to innovate and lower costs. Thus, in the long-run, because competitive generators will be more hesitant to invest and because investors will demand higher returns to compensate for the additional financial risk, market prices will actually increase even more.

Thus, developing subsidized generation by regulatory mandate (and subsidized generation selected by a competitive bidding process is still subsidized generation) deters competitive development of new generating resources by competitive generation suppliers. Why would competitive suppliers wish to risk their capital in New Jersey if the BPU, through LCAPP mandates, can destroy the value of generation investments they might make?

As shown in Figure 2, that strong investment disincentive leads to higher prices in the long run.

Figure 2: Price Path with Subsidized Generation



Although, as shown in Figure 2, artificial subsidies can temporarily reduce prices, the costs will always be greater in the long run. You cannot subsidize your way to more robust competitive markets: subsidies drive out legitimate competitors just as Gresham's law states that, "Bad money drives out good."[20] If New Jersey continues the LCAPP approach, or pursues other non-market measures, such as mandating that EDCs sign long-term bilateral contracts with new generation suppliers,[21] the unintended adverse consequences will only multiply.

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[20] Gresham's Law is named after Sir Thomas Gresham (1519–1579), an English financier.

[21] In FERC Docket No. EL11-20, the IMM commented on allowed exceptions to the MOPR Rule. As stated, and repeated in the IMM's comments of June 17, 2011 in this BPU docket,

> Market entities including public power agencies and LSEs may wish to enter into long term contracts for physical supply, or to buy or build under a range of options not incorporated in the one year RPM auctions. If the market entity conducts a verifiably open, competitive, non-discriminatory process for acquiring such a contract, the resultant contract with the lowest cost supplier would pass MOPR under the exception process. If the self-build option were similarly demonstrated to be the least-cost option using a competitive process, even if it were funded using the standard regulatory rate base rate

Thus, New Jersey should end its non-market policies and, instead, signal a long-term commitment to the PJM RPM. New Jersey could also take other actions to incent new investment, such as streamlining the environmental siting and permitting process for new generating facilities.

III. IS THE RPM CONSTRUCT CAPABLE OF SIGNALING THE NEED FOR SPECIFIC TYPES OF GENERATION CAPACITY, IN PARTICULAR MID-MERIT AND BASELOAD CAPACITY?

That greenfield baseload and mid-merit generation has not been developed is not evidence that the PJM RPM cannot support such investment. As discussed previously, new baseload and mid-merit generation has already been developed through less costly capacity uprates and generator repowerings. The availability of such lower-cost alternatives and continuing ample reserve margins in PJM provide a clear signal that there is no need to develop more baseload and mid-merit resources in PJM.

In part, too, the lack of new generation is a function of an inability to develop certain types of baseload generation. No developer, for example, is likely to propose a new baseload coal-fired generator, because of environmental opposition. New nuclear generation is so expensive that any near term development of any new nuclear plant is a "bet the company" proposition, which leaves new baseload and mid-merit gas-fired generation, specifically combined-cycle plants.

of return approach, then it would also pass MOPR under the exception process. (IMM Comments, June 17, 2011, at 4.)

RPM can incent development, if the demand for such generation actually exists. PJM has recommended augmenting RPM with voluntary longer-term capacity auctions. That recommendation is also supported by the August 26, 2011, Brattle Report that evaluated the PJM market.

> To increase forward price transparency and facilitate bilateral long-term contracting, we also support PJM's effort to add centralized but voluntary auctions for long-term capacity products as a supplement to the 3-year forward base auctions (e.g., for a duration of 3, 5, and 7 years starting with the BRA delivery year). Such voluntary long-term auctions or an over-the-counter trading platform for long-term capacity products would increase the transparency and liquidity of the long-term capacity market without risking the kinds of distortions that would be caused to auction prices if the prices for a single delivery year could be locked for multiple years in by broadening the New Entry Pricing Adjustment ("NEPA") or introducing mandatory long-term procurement.[22]

The Brattle Report also recommends the RPM auction maintain its 3-year forward design. As the report states, "Given the increase in commitment related risks, we do not believe that extending the forward periods beyond three years would be a cost-effective option to provide increased long-term pricing certainty."[23] In other words, extending the period for which capacity suppliers must commit, while providing longer-term price certainty that could enhance

[22] Brattle Report at viii.

[23] *Id*. at 155.

investment, is not free. Rather, asking suppliers for longer-term commitments increases the opportunity cost.[24]

Because of the underlying high costs, the Brattle Report also recommends against <u>mandatory</u> long-term contracting under the RPM, stating,

> [i]mplementing such a concept would require PJM to make important decisions about major long-term contract terms: (1) how much total capacity should be procured under such long-term contracts … and (2) what should be the contract term … Procuring too much capacity under long-term commitments could significantly increase deficiency risks for suppliers, particularly suppliers of existing resources that could become unavailable over time. Because the added risk may offset some or all of the reduced financing risk for new plants or existing plants with major investment needs, procuring too much capacity through such long-term arrangements could increase total costs.[25]

A voluntary longer-term auction thus makes more economic sense, and will be more cost effective because it provides capacity suppliers and LSEs with greater flexibility. Although RPM is designed to be neutral with respect to the types of capacity incented, from an economic standpoint, RPM's design is also less important to incent new baseload and mid-merit resources because such units depend less on capacity revenues for their economic viability than do peaking resources. Unlike peakers, they obtain most of their revenue from energy, not

[24] This is really the same economic effect that explains why 30-year mortgage rates are generally higher than 15-year rates: the lender must commit to a longer-term loan of the funds, which means those funds will not be available for other investments.

[25] *Id*. at 156-57.

capacity, markets. Thus, decisions to construct new baseload and mid-merit generation will depend less on expectations of RPM prices, and more on expectations of wholesale energy prices.

Finally, the economic downturn, which has reduced the overall demand for electricity and increased reserve margins has decreased the need for new baseload and new mid-merit generation. As the economy recovers and uncertainties about future capacity supplies are resolved, *e.g.*, how much capacity will retire with implementation of new environmental regulations, market signals for new baseload and mid-merit capacity will become much clearer.

IV. SHOULD THE STATE OF NEW JERSEY PURSUE THE FIXED RESOURCE REQUIREMENT ("FRR") ALTERNATIVE AS A MEANS OF DEVELOPING ADEQUATE NEW GENERATION CAPACITY RESOURCES?

Under PJM's Reliability Assurance Agreement (RAA), EDCs and competitive retail suppliers can elect to opt out of participating in RPM and supply all of their capacity through the FRR alternative. Under FRR, an LSE agrees to provide all capacity requirements in its load zone. The FRR election allows eligible LSEs – whether they are EDCs or competitive retail suppliers – to submit a FRR capacity plan and meet a fixed capacity requirement as an alternative to participating in the RPM capacity auction.[26] By electing to become a FRR, an LSE avoids paying the RPM capacity prices. Any eligible LSE can elect this option so long as it complies with the FRR requirements, including both

[26] *See* PJM Reliability Assurance Agreement, Schedule 8.1, Sec. D ("FRR Capacity Plans").

advance notice and the identification of adequate reliability resources. The FRR designation requires a minimum commitment of at least five years.[27]

Once an FRR is in place, no other LSE within the FRR area can establish its own FRR plan until the existing FRR ends. As such, other potential capacity suppliers are "locked out" of the market, and ratepayers and other LSEs are captive customers of the existing FRR entity. The key issue in electing the FRR option is the price at which an FRR entity will sell capacity, both to its own customers (*e.g.*, an EDC) and to customers who take service from competitive retail suppliers. Specifically, the seminal question is: If New Jersey EDCs opted out of the PJM RPM and became FRR entities, would the resulting capacity prices be lower than the PJM RPM prices and thus lower costs for New Jersey consumers? The answer is <u>no</u>.

Ohio's experience is instructive. AEP Ohio and Duke Ohio are the only two FRR entities in PJM. The recent experience with these companies indicates an FRR designation provides an opportunity to charge above, not below-market prices for capacity.

PJM's RAA addresses how a FRR entity will be compensated if a customer switches to a competitive retail supplier. The key is whether the state regulator in which the FRR entity is located has established a compensation mechanism. Otherwise, the default compensation, *i.e.*, the price that a competitive retail supplier would pay the FRR entity, is the PJM rest-of-pool (RTO) RPM market-clearing price. As stated in the RAA:

[27] *Id*. at Schedule 8.1, Section C(2).

> In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's costs or such other basis shown to be just and reasonable.[28]

Both AEP Ohio and Duke Ohio currently have applications pending before the Public Utility Commission of Ohio to establish their default or "standard service offer" rates.[29] The Public Utility Commission of Ohio had previously established that the appropriate price for competitive retail suppliers to pay AEP Ohio for capacity was also the PJM RPM market-clearing price. AEP Ohio has challenged that price, and challenged FERC. Specifically, AEP Ohio argues that, as an FRR entity, it is entitled to recovering its full embedded capacity costs.

AEP Ohio estimated its embedded capacity costs, based on 2010 data published in its FERC Form-1 reports, at about $355/MW-day.[30] In sharp contrast, the average RPM RTO market-price for the 2011/12 planning year,

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[28] *Id*. at Schedule 8.1, Section D(1)(8).

[29] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan*, Case Nos. 11-346-EL-SSO and 11-348-EL-SSO; *In the Matter of the Application of Duke Energy Ohio and to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan*, Case No. 11-3549-EL-SSO.

[30] *See* Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, Direct testimony of Kelly D. Pearce in support of the Stipulation and Recommendation on behalf of Columbus Southern Power Company and Ohio Power Company, September 13, 2011, Exhibits KDP-1 and KDP-2. This testimony is part of a contested partial Stipulation that AEP Ohio filed with the PUCO on September 7, 2011.

which began on June 1, 2011, through the 2014/15 planning year, is $70/MW-day. **Thus, under its FRR, AEP sought to charge shopping customers for capacity at five times the market**.

Duke Ohio proposed to charge all customers, both shopping and non-shopping ones, for capacity at its embedded cost, net of 80% of the profits it receives from off-system energy and capacity sales. **Duke projected the resulting capacity charges to average about $220/MW-day over the four-year planning period, less than the AEP Ohio price, but still over three times the average PJM RPM market-clearing price.**

Notably, however, if these two companies' embedded capacity costs had been less than the RPM market-clearing prices, without a doubt they would not have proposed charging their customers and competitive retail suppliers below-market prices for their capacity. Instead, they would readily agree to charge the RPM market price. Moreover, it would make economic sense for them to be allowed to charge that higher market price, and not be forced to charge a below-market, cost-based price. The reason is that, under a FRR, the capacity price charged by a LSE is what economists call a "transfer price," and, in the presence of an outside market, the economically efficient transfer price <u>is</u> the market price.

A transfer price is simply a price that one part of a company charges another part. AEP Ohio's and Duke Ohio's capacity prices can be thought of as an internal transfer price of capacity sold to standard service offer (SSO) customers and competitive retail suppliers. Rather than purchasing capacity from the market, SSO customers and competitive retail suppliers must purchase capacity from AEP Ohio and Duke Ohio.

When there is an external market for the good being "transferred" internally, the most efficient price is the external market-clearing price. If the transfer price is higher than the market price, then the company division purchasing the commodity would benefit by directly buying from the market. Conversely, if the transfer price is lower than the market price, then the company division selling the commodity would lose money by subsidizing the other division's purchases.

It is highly unlikely that either the BPU or FERC would, or could, enforce requirements that FRR entities in New Jersey charge below-market capacity prices.[31] Nor would such "below-market" capacity be sold voluntarily. Thus, any suggestion that having New Jersey EDCs become FRR entities would reduce the cost of capacity to New Jersey consumers, has no economic basis. In essence, it would simply be another manifestation of LCAPP, with the unintended adverse consequences I have previously described.

V. PJM'S RPM MARKET IS COMPETITIVE

Together, PJM's IMM, along with stringent participation, and bid-setting rules prevent seller-side market manipulation and help ensure competitive outcomes. Significantly, the IMM has repeatedly found that although structural market power exists based on the distribution of generation capacity ownership, the RPM market results are competitive. As stated in the 2010 State of the Market Report (2010 SOMR), "Market performance was evaluated as

[31] Forcing an EDC to charge a below-market capacity price could be subject to legal challenge as a "regulatory taking."

competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules."[32]

PJM's strong RPM rules successfully prevent market power abuses. First, generators may not physically withhold capacity from the market. All generators that participate in the RPM <u>must</u> bid all capacity into the auction "unless they have a contract with an entity outside PJM or are physically unable to perform or are committed to an FRR entity."[33] Furthermore, generators cannot engage in "economic withholding," that is, bidding strategically to ensure their bids will not be accepted so as to raise the RPM market-clearing price.[34] Rather, to prevent any such "economic withholding", for all generators that fail structural market power tests, the IMM strictly enforces offer caps, based on the generators' avoided costs.

Some have also questioned the competitiveness of PJM's RPM by highlighting the entire capacity market is an administrative construct. This criticism is without merit. As Lesser and Israilevich (2005)[35] discuss, the capacity

[32] 2010 SOMR, Volume 2, Section 5, at 349. In addition, generators have a strong <u>disincentive</u> to "withhold" capacity by not maintaining their facilities. The reason is that generators are paid based on the EFORd values of their units, essentially a measure of generator forced outage rates. The greater a generating unit's EFORd, the less unforced capacity it provides per MW of installed capacity, and the less it is paid by PJM. See PJM Manual M-22, *Generator Resource Performance Indices*, for the specific formula used.

[33] *Id*. at 359.

[34] Generators whose resources clear in the RPM are also required to bid into the day-ahead energy market, to ensure the energy market is competitive.

[35] J. Lesser and G. Israilevich "The Capacity Market Enigma," *Public Utilities Fortnightly* 143 (December 2005): 38-42 ("Lesser and Israilevich 2005").

market offers a market mechanism for providing a public good: reliability. This is no different conceptually than the U.S. EPA creating a market mechanism to provide the public good of cleaner air by establishing emissions markets for SO2 and NOx under the Energy Policy Act of 1992. By providing an open, transparent, competitive mechanism through which emissions allowances could be bought and sold, EPA ensured specific emissions reductions targets could be achieved at the lowest possible cost. Similarly, the PJM capacity market provides the desired level of reliability by creating incentives for first developing the lowest-cost capacity resources. This is why generators, including incumbent generators, have added thousands of MW of new capacity through uprates and generator repowerings. It is also why over 14,000 MW of demand-response resources cleared in the 2014/15 BRA auction. If incumbent generators were somehow exercising market power and controlling the PJM capacity market, they would <u>not</u> add new capacity and they would prevent any demand response from being bid in.

VI. CONCLUSIONS AND RECOMMENDATIONS

The continuing clamor for non-market approaches signals to market participants that the rules are likely to change, and only serves to exacerbate the very concerns raised by the BPU. Mandating development of specific generating resources and saddling consumers with administratively determined long-term contracts drives out competitive generation developers, increases regulatory uncertainty, and forces consumers to bear the risks of high cost generating resources. This conflicts directly with electric restructuring's key goal of shifting such risks from consumers to generation developers, who are best able to address them, and illustrate the unintended adverse consequences of policies seeking "end-runs" around markets.

Ultimately, the problem with implementing non-market solutions is it substitutes the judgment of politicians and regulators, however well-intentioned, for the rigorous discipline of the marketplace. Yet history has proven repeatedly that politicians and regulators fare far worse than markets in determining the most cost effective resources.

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Fundamental economic principles show that the RPM is working, and working well. Because of the IMM's efforts, the results of the RPM auctions are competitive. New, lower-cost generating resources continue to be developed first, as they should be in a well-functioning market. The entry of these resources continues to result in market-clearing prices that are less than net CONE. Moreover, because of reduced electric demand and changes in PJM planning parameters, as well as anticipated increases in new transmission capacity, generation developers are almost certainly factoring in expectations of lower capacity prices in New Jersey in the future. Thus, any lack of new generating baseload and mid-merit capacity resources, is evidence not of market failure, but of a well-functioning capacity market.

Yet, some parties continue to recommend a "command and control" oriented approach towards generation procurement. For example, PPANJ-APPA's June 2011 comments asserted one of their central goals was for longer-term bilateral agreements and resource ownership to become the primary methods of obtaining generation and demand-side resources, along with an eventual phase-out of mandatory centralized capacity markets."[36] In other words, a return to the failed policies of the past, in which electricity is owned by vertically integrated electric utilities, and generation investments will be determined by regulators, presumably based on long-term resource planning exercises. Respectfully, I suggest that "back to the future" is a poor policy prescription for New Jersey. It did not work in the past, and there is every reason to expect it will not work in the future.

Thus, I recommend the BPU resist the urge to "do something" and let the RPM work as it is intended. The recommendations by the IMM and in the Brattle Report should further improve RPM's performance, and the ability to participate in voluntary longer-term auctions should provide greater price certainty to those who want it. By letting the RPM market work, and publicly signaling it will do so, the BPU will send the best possible signals to potential developers.

[36] *Id*. at 3.